KEEGAN, WERLIN & PABIAN, LLP

ATTORNEYS AT LAW
265 FRANKLIN STREET
BOSTON, MASSACHUSETTS 02110-3113

(617) 951-1400

TELECOPIERS:
(617) 951-1354
(617) 951-0586

October 7, 2004

Mary L. Cottrell, Secretary
Department of Telecommunication and Energy
One South Station, 2nd Floor
Boston, MA 02202

Re: Boston Edison Company, D.T.E. 04-68

Dear Secretary Cottrell:

Enclosed please find the response of Boston Edison Company d/b/a NSTAR Electric ("Boston Edison") to discovery questions asked by the Attorney General and the Department of Telecommunications and Energy in the above-referenced proceeding, as listed on the following Discovery Log. Please note that the attachments that are responsive to these questions are confidential and are being filed under separate cover with the Attorney General and the Hearing Officer only.

Thank you for your attention to this matter.

Very truly yours,

John K. Habib

John K. Habib

Enclosures

cc: Service List
Joan Foster Evans, Hearing Officer (2)
Colleen McConnell, Assistant Attorney General (2)

Thank you for your attention to this matter.

Very truly yours,

John K. Habib

John K. Habib

Enclosures

cc: Service List (transmittal letter only)
Mary L. Cottrell (transmittal letter only)
Colleen McConnell, Assistant Attorney General (2)

LOG OF RESPONSES FILED

D.T.E. 04-68

October 7, 2004

Response	Status	Attachments
DTE-1-1	Filed October 4, 2004	Exhibits BEC-GOL-2 through 8 on **CONFIDENTIAL CD-ROM**
DTE-1-2	Filed October 4, 2004	
DTE-1-3	Filed October 5, 2004	Attachments DTE-1-3 (a) through (c), each **CONFIDENTIAL.** Attachment DTE-1-3 (d) **BULK CONFIDENTIAL CD-ROM**
DTE-1-4	Filed October 4, 2004	
DTE-1-5	Filed October 1, 2004	
DTE-1-6	Filed October 4, 2004	Attachment DTE-1-6 **CONFIDENTIAL CD-ROM**
DTE-1-7	Filed October 4, 2004	Attachment DTE-1-7 **CONFIDENTIAL**
DTE-1-8	Filed October 1, 2004	
DTE-1-9	Filed Sept. 28	
DTE-1-10	Filed October 1, 2004	Attachment DTE-1-10
DTE-1-11	Filed October 4, 2004	Attachment DTE-11 **CONFIDENTIAL CD-ROM**
DTE-1-12	Filed October 1, 2004	
DTE-1-13	Filed October 1, 2004	
DTE-1-14	Filed October 4, 2004	
DTE-1-15	Filed Sept. 28	
DTE-1-16	Filed Sept. 28	
DTE-1-17	Filed Sept. 28	
DTE-1-18	Filed Sept. 28	
DTE-1-19	Filed Sept. 28	
DTE-2-1	Filed Herewith	
DTE-2-2		
DTE-2-3	Filed Herewith	
DTE-2-4		
DTE-2-5		
DTE-2-6		
DTE-2-7	Filed Herewith	
DTE-2-8	Filed Herewith	
DTE-2-9	Filed Herewith	
DTE-2-10	Filed Herewith	
DTE-2-11		
DTE-2-12	Filed Herewith	
DTE-2-13	Filed Herewith	Attachment DTE-2-13 **CONFIDENTIAL CD-ROM**

Response	Status	Attachments
DTE-2-14	Filed Herewith **CONFIDENTIAL**	
DTE-2-15	Filed Herewith	
DTE-2-16	Filed Herewith	
DTE-2-17		
DTE-2-18		
DTE-2-19	Filed Herewith	
DTE-2-20	Filed Herewith	
DTE-2-21	Filed Herewith	
DTE-2-22	Filed Herewith	
DTE-2-23		
DTE-2-24		
DTE-2-25		
DTE-2-26	Filed Herewith	Attachment DTE 2-26 **CONFIDENTIAL**
DTE-2-27	Filed Herewith	
DTE-2-28		
DTE-2-29		
DTE-2-30		
AG-1-1	Filed October 1, 2004	Attachments AG-1-1(A) through (Q) **BULK**
AG-1-2	Filed Sept. 28	Attachments AG-1-2 (a) through (g) each **CONFIDENTIAL**
AG-1-3	Filed Sept. 28	Attachments AG-1-3(a) and (b), each **CONFIDENTIAL**
AG-1-4	Filed Sept. 28	Attachment AG-1-4
AG-1-5	Filed October 4, 2004	Attachments AG-1-5 (a) through (d), each **CONFIDENTIAL** Attachment AG-1-5 (e) **CONFIDENTIAL CD-ROM**
AG-1-6	Filed Sept. 28	
AG-1-7	Filed October 1, 2004	
AG-1-8	Filed Sept. 28	
AG-1-9	Filed Sept. 28	Attachment AG-1-9
AG-1-10	Filed Sept. 28	Attachment AG-1-10
AG-1-11	Filed Sept. 28	Attachments AG-1-11(a) and (b), each **CONFIDENTIAL CD-ROM**
AG-1-12	Filed Sept. 28	Attachment AG-1-12
AG-1-13	Filed Sept. 28	Attachment AG-1-13
AG-1-14	Filed Sept. 28	Attachment AG-1-14 **CONFIDENTIAL CD-ROM**
AG-1-15	Filed Sept. 28	Attachments AG-1-15(a) and (b) each **CONFIDENTIAL CD-ROM**
AG-1-16	Filed Sept. 28	
AG-1-17	Filed Sept. 28	
AG-1-18	Filed Sept. 28	
AG-1-19	Filed Sept. 28	Attachment AG-1-19
AG-1-20	Filed Sept. 28	Attachment AG-1-20

Response	Status	Attachments
AG-1-21	Filed Sept. 28	
AG-1-22	Filed October 4, 2004	Attachment AG-1-22 **CONFIDENTIAL CD-ROM**
AG-1-23	Filed Sept. 28	
AG-1-24	Filed Sept. 28	
AG-1-25	Filed October 4, 2004	
AG-1-26	Filed October 4, 2004	Attachment AG-1-26 **CONFIDENTIAL CD-ROM**
AG-1-27	Filed October 4, 2004	
AG-1-28	Filed Sept. 28	
AG-1-29	Filed October 4, 2004	
AG-1-30	Filed October 4, 2004	Attachment AG-1-30 **CONFIDENTIAL**
AG-2-1	Filed October 4, 2004	Attachment AG 2-1 **BULK**
AG-2-2	Filed Sept. 28	
AG-2-3	Filed Sept. 28	
AG-2-4	Filed Sept. 28	
AG-2-5	Filed Sept. 28	Attachment AG-2-5 **CONFIDENTIAL (CD-ROM)**
AG-2-6	Filed October 1, 2004	
AG-2-7	Filed October 4	Attachments AG-2-7(A)and (B)
AG-2-8	Filed October 4	Attachments AG-2-8 (A), (B) and (C)
AG-2-9	Filed October 4	Attachments AG-2-9 (A) and (B)
AG-2-10	Filed October 4	Attachment AG-2-10
AG-3-1	Filed Herewith	Attachments AG-3-1(a) through (j)
AG-3-2	Filed Herewith	
AG-3-3	Filed Herewith	
AG-3-4	Filed Herewith	

Information Request DTE-2-1

Refer to AG-1-13 and AG-1-20. Please explain the decrease in capacity factor for OSP Units 1 and 2 over time. Provide electronic copies in Microsoft Excel format of the underlying data.

Response

Capacity factors submitted in Attachment AG-1-13 and Attachment AG-1-20 were compiled from OSP reports. The impacts of shifts in pricing strategies detailed in the Company's response to Information Request DTE-2-29 and the Arbitration Decision detailed in Information Request DTE-2-30 together with the age of the OSP units and the early 2004 outages resulted in the decreased capacity factor.

In addition, the new pricing methodology at the center of the dispute detailed in the Company's response in Information Request AG-3-1 contributed to the reduced dispatch of the OSP units. Furthermore, at the November 2003 OSP Operating Committee meeting, it was discussed that the previous practice of running one unit at base load (60 MW) during off peak hours for the purpose of "keeping the plant warm" was becoming costly and would be eliminated. Additionally, at that same meeting, an increase in bid price due to increased maintenance costs was discussed and recommended.

Information Request DTE-2-3

Refer to CONFIDENTIAL Attachments AG-1-11, and AG-1-14, worksheets "OSP 1" and "OSP2." How sensitive are the saving analyses to a change in capacity factor?

Response

Scenarios regarding changes in the capacity factor must take into consideration the Gas Layoff Credit (see response to Information Request DTE-2-14). As demonstrated in the responses to Information Requests AG-1-12, AG-1-13, AG-1-14 and AG-1-15, historically there has been an inverse relationship between unit capacity factors and the Gas Layoff Credits (i.e., as the capacity decreases, more gas supply or pipeline capacity is available for resale and the credit increases). Consequently, it would be improper to adjust the capacity factor without making a corresponding change in the projected Gas Layoff Credit. Sensitivity analyses of the percent savings, based on the average annual capacity, heat rate and gas layoff credit assumptions contained in Attachment AG-1-14, Attachment AG-1-11(a) and Attachment AG-1-11(b) are provided in the following tables:

Attachment AG-1-14: Sensitivities

Capacity Factor	Unit 1 Gas Layoff (2004)	Unit 2 Gas Layoff (2004)	Percent Savings
30%	($20,253,202)	($20,253,202)	6.25%
50%	($14,466,573)	($14,466,573)	10.17%
80%	($5,786,629)	($5,786,629)	16.03%

Attachment AG-1-11(a): Sensitivities

Capacity Factor	Unit 1 Gas Layoff (2004)	Unit 2 Gas Layoff (2004)	Percent Savings
30%	($18,227,882)	($18,227,882)	7.52%
50%	($13,019,916)	($13,019,916)	11.65%
80%	($5,207,966)	($5,207,966)	17.75%

Attachment AG-1-11(b): Sensitivities

Capacity Factor	Unit 1 Gas Layoff (2004)	Unit 2 Gas Layoff (2004)	Percent Savings
30%	($22,278,522)	($22,278,522)	4.96%
50%	($15,913,230)	($15,913,230)	8.63%
80%	($6,365,292)	($6,365,292)	14.23%

Information Request DTE-2-7

Refer to CONFIDENTIAL Attachment AG-1-14, worksheets "OSP 1" and "OSP2." Please explain the derivation of the values in cell D13. Please provide electronic copies in Microsoft Excel format of any underlying data used.

Response

Cell D13 represents the ten-year heat rate projection from Attachment AG-1-15 (a) **(CONFIDENTIAL CD-ROM)**, *OSP Budget – Henwood Gas Price Update,* beginning in cell H250 S250, years 1997 through 2008 for both OSP unit 1 and OSP unit 2. Please refer to the response to Information Response AG-2-10, Attachment AG-2-10 for the history of each unit's heat rate for each month of operation since the original start date. Cell D13 in OSP 1 also represents the average heat rate for the last 24 months as shown in Attachment AG-2-10. For OSP 2, the average historical heat rate for the last 24 months was 9,770. Given that OSP Unit 2 recent heat rates have been considerably lower than the 24 month average, CEA believed this heat rate was too high for forecasting purposes and took a conservative approach by utilizing the OSP 1 heat rate.

Information Request DTE-2-8

Refer to CONFIDENTIAL Attachment AG-1-14, worksheet "OSP 1." Please explain the use of the values in cells J11, J12, K11, and K12.

Response

Cells J11, J12, K11 and K12 found in Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**, worksheet *OSP 1*, are not used in any calculations. While these cells fall within the lookup field for Column B of the OSP 1&2 AN worksheet, which starts at the date row (row 9) and ends with the NSTAR Electric entitlement row (Row 25), these numbers are not used.

Information Request DTE-2-9

Refer to CONFIDENTIAL Attachment AG-1-14, worksheets "OSP 1" and "OSP2." Please explain the derivation of the values in cells in row 18, cells E through K. Please provide electronic copies in Microsoft Excel format of any data used to derive those values not linked to other cells in the worksheet.

Response

The Total Fuel Commodity Charge found in row 18 of Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**, worksheets, *OSP 1* and *OSP 2*, in cells E through K are calculated using the average of the winter and summer plant capacity of 301.6 MW times the heat rate of the unit (as described in responses to Information Request DTE-2-7) times the assumed capacity factor (as described in the responses to Information Request DTE-2-2) times 8.76 (thousand hours/year) times the unitized commodity cost in row 93. The unitized commodity cost is calculated in Attachment AG-1-15(a) **(CONFIDENTIAL CD-ROM)** in row 356. The Total Commodity Rate is calculated by adding the total Progas Contract Commodity, the TGP Commodity and the TGP Fuel.

Information Request DTE-2-10

Refer to CONFIDENTIAL Attachment AG-1-14, worksheets "OSP 1" and "OSP2." Please explain the choice of the values contained in the formulas in row 19. Please provide electronic copies in Microsoft Excel format of any data used to derive these values.

Response

The values contained in row 19 of Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**, worksheets OSP 1 and OSP 2 include the Gas Layoff Credit to the Demand Charge that are described in the power agreement in article seven, section ten, Credit of Revenues for Resale of Gas. To calculate this credit through the end of each of the contracts, CEA used the Company's estimated portion of the projected total gas layoff of $4.4 million and grossed that amount up (based on the Company's 23.5 percent entitlement) for the full unit. (Please refer to the response to Information Request DTE-2-14 for an explanation of how the $4.4 million gas layoff credit was derived.) The gas layoff credit in row 19 is then escalated up or down based on the change from year to year in the Louisiana Spot Gas prices.

Information Request DTE-2-12

Refer to CONFIDENTIAL Attachment AG-1-14, worksheet "Summary Nom." Please explain the inclusion of cell D51 in the formula contained in cell L51.

Response

Cell D51 in Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**, worksheet Summary Nom should not have been included in the worksheet. The OSP 1 contract terminates on December 31, 2010. This inclusion has no effect on the calculated savings under the OSP 1 contract.

Information Request DTE-2-13

Refer to CONFIDENTIAL Attachment AG-1-14, worksheet "Exhibit 6A." Please explain the derivation of the values in cell C25. Please provide electronic copies in Microsoft Excel format of any data used to derive these values.

Response

CONFIDENTIAL ATTACHMENT

Please refer to Attachment DTE-2-13 **(CONFIDENTIAL CD-ROM)**, beginning with cell D15, for the calculation of Cell C25 on worksheet, Exhibit 6A of Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**. This payment stream shows the monthly (for 2004 through 2006) and annual (for years 2007 through 2011) values of the OSP Termination Price.

Information Request DTE-2-14

Refer to CONFIDENTIAL Attachment AG-1-14, worksheets "Exhibit 6B" and "Exhibit 6C." Please explain the gas revenues discussed in footnote 4. Include any reference to the Purchased Power contract, as well as any assumptions used to derive the value listed. Please provide electronic copies in Microsoft Excel format of any data used to derive these values.

Response

REDACTED RESPONSE

The Gas Layoff Credit is referenced in article seven, section ten of the Purchased Power contract (see also responses to Information Request AG-1-12 and Information Request AG-1-24).

As noted in footnote 4 of Exhibits 6B and 6C of Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**, the Company estimated its allocation of the annual Layoff Credit to be **[REDACTED]** million for OSP 1 and OSP 2, respectively. On a per-unit basis, the estimated Layoff Credit is approximately **[REDACTED]**. Based on the data provided in Attachments AG-1-12 and AG-1-19, the projected per-unit Layoff Credit **[REDACTED]** is approximately equal the average per-unit credit of approximately **[REDACTED]** million for the period 1999 through 2003[1]. As discussed in footnote 4 (referenced above), the initial **[REDACTED]** million credit was increased or decreased annually based on projected changes in the Louisiana gas price.

1 It also should be noted that the unit capacity factors during that time ranged from approximately 30 percent to over 60 percent.

Information Request DTE-2-15

Refer to CONFIDENTIAL AG-1-15(a) worksheets "OSP 1" and "OSP2." Please provide underlying electronic copies in Microsoft Excel format of all data and calculations used to derive all fuel price assumptions. Include source information.

Response

The fuel price assumptions found in Attachment AG-1-15(a) **(CONFIDENTIAL CD-ROM),** worksheets, OSP1, OSP2, that are used to calculate the Total unitized commodity costs utilized in Attachment AG-1-14 **(CONFIDENTIAL CD-ROM)**, worksheets OSP 1 and OSP 2, were derived by taking the sum of the Contract Commodity (row 352), the TGP Commodity (row 352) and the TGP Fuel (row 355) rates. The Contract Commodity rate was changed from the original OSP budget by inserting the Henwood NEPOOL prices (found in Attachment AG-1-26, *Fall 2003 Northeast Monthly Natural Gas Price* and *Northeast Short Term Forecast Appendix_May 2004*) and backing out the TGP rate (row 346).

Information Request DTE-2-16

Refer to CONFIDENTIAL AG-1-15(a) worksheets "OSP 1" and "OSP2." Please define "AFFC Base" and "NEPOOL AFFC Proxy."

Response

"AFFC Base" and "NEPOOL AFFC Proxy" were components of the Commodity Charge of the ProGas Gas Purchase Contract for the first ten years following commercial operation of the plant. As specified in Paragraph 8 of the Gas Purchase Contract, subsequent to the first ten years after commercial operation, the commodity charge is subject to renegotiation. Consequently, the "AFFC Base" and NEPOOL AFFC Proxy" are no longer applicable and not used in Attachment AG-1-15(a) **(CONFIDENTIAL CD-ROM)** during the forecast period 2004 through 2011.

Information Request DTE-2-19

Refer to CONFIDENTIAL AG-1-15(a) worksheets "OSP 1," "OSP2," and "OSP 1 and OSP2." Please define and explain the boxes labeled "ITC Amortization."

Response

"ITC Amortization" refers to the amortization of investment tax credits associated with vintage year capital expenditures. Since there are no such credits associated with OSP 2, the ITC amortization has no effect on the OSP 2 income tax calculation. For OSP 1, the ITC amortization serves to offset taxable income and, therefore, the projected current tax expense.

Information Request DTE-2-20

Refer to CONFIDENTATIAL AG-1-15(a) worksheet "OSP 2". Please explain the rationale for using OSP 1 Debt values for OSP 2 analysis.

Response

The OSP 1 Debt values are not being used for OSP 2 analysis. OSP 2 debt is calculated in row 467 of worksheet OSP 2 while the OSP 1 debt is calculated in row 452 of worksheet OSP1 in Attachment AG-1-15(a) **(CONFIDENTIAL CD-ROM)**. The OSP 2, 6.52 percent senior note is as shown in the calculation of row 464 and the OSP 1, 7.9 percent senior note is as shown in the calculation of row 449.

Information Request DTE-2-21

Refer to CONFIDENTIAL AG-1-15(a) worksheet "OSP 1," "OSP 2," and "OSP 1 and OSP 2." Please reconcile the difference in values in cell T15.

Response

Cell T15 or the "Revolver Debt" in Attachment AG-1-15 (a) **(CONFIDENTIAL CD-ROM)**, worksheets, *OSP1*, *OSP 2* and *OSP 1 and OSP 2* is no longer active and the debt is paid off; therefore the differences in these cells do not affect any of the values in the budget.

Information Request DTE-2-22

Refer to CONFIDENTIAL AG-1-15(a) worksheets "OSP 1," "OSP2," and "OSP 1 and OSP2." Please reconcile the difference in the first year multiplier used in columns Q and V with each other and between worksheets.

Response

The multiplier in worksheet *OSP 1 and OSP2* is not active. Cells N9 through N15 of that worksheet sum the Turnkey additions from both the *OSP 1* and *OSP 2* worksheets. The OSP 1 multipliers are calculated in rows 387 through 396 of the *OSP 1* worksheet and the OSP 2 multipliers are calculated in rows 402 through 411 of the *OSP 2* worksheet. Since the multipliers are associated with capital additions at the respective OSP1 and OSP2 units, there is no need to reconcile the multipliers between the OSP1 and OSP2 worksheets.

Information Request DTE-2-26

Refer to CONFIDENTIAL Attachment AG-1-2 (h) regarding the TransCanada Bid on NSTAR/BECo PPA Entitlements. Please provide the "bid form (excel file) - two sheets: OSP I and OSP II" to which notation #2) refers as well as the "bid letter", the Entitlement Transfer Agreement and the Guaranty Agreement that were included in the original December 03, 2003 e-mail.

Response

CONFIDENTIAL ATTACHMENT

Please see Attachment DTE-2-26 **(CONFIDENTIAL).**

Information Request DTE-2-27

Refer to the Company's response to IR-DTE 1-10. Please re-work the spreadsheet to facilitate an "apple to apple" comparison, by 1) explicitly quantifying Bidder A's dollar amount bid for the OSP contracts, and 2) either quantifying bidder A and C's bid and D's initial bid in terms of an annual amount or by quantifying bidder D's final bid in terms of a monthly amount.

Response

Please note that Bidder A did not provide a separate bid for the OSP contracts. Consequently, the comparison requested in item 1), above cannot be quantified. Regarding item 2), please note that the response to Information Request DTE-1-10 provides monthly amounts for Bidder D's bid.

Information Request AG-3-1

Please provide a complete and detailed description of all claims and disputes brought by the Company against Ocean State Power associated with the Ocean State Power contracts. Please also provide for each claim and dispute a description of its current status along with copies of all pleadings and filings associated with any arbitration and / or judicial action.

Response

There have been no formal disputes between the Company and Ocean State Power ("OSP") associated with the contracts. However, during the period of March 1999 through June 1999, Boston Edison and Ocean State Power ("OSP") had several discussions and exchanged correspondence regarding the methodology for calculating the fuel price to be provided to ISO-NE for determining the dispatch of OSP's generating units. Please refer to Attachments AG-3-1(a) through AG-3-1(e) for correspondence concerning this matter. In February 1999, TransCanada Power Marketing, as Lead Participant for the OSP Units, determined the then-existing methodology for determining replacement fuel prices for OSP was incorrect and had used a procedure under which the price for the firm gas supply was based on an index for gas available at a hub (Gas Daily Midpoint price for Niagara) through which the OSP gas is transported. Implementation of this new pricing methodology resulted in a reduced dispatch of the OSP units. However, under the terms of the OSP Agreement, which is a cost-of-service-type agreement, the Company received revenues from the sale of excess gas as a result of the reduced dispatch of the OSP units. The Company flowed through the full amount of the credits to customers through the reconciliation of is transition charges. Please see the response to Information Request DTE-1-3.

In addition, during the July 1991 through February 1992 period, Boston Edison and OSP had several discussions on the interpretation of the contractual language on how the Equivalent Availability Factor calculation should be performed. Please refer to Attachments AG-3-1(f) through AG-3-1(j) for correspondence on this matter. This dispute was resolved as indicated in the attachments.

Attachment
AG-3-1(a)

Boston Edison
A BEC ENERGY COMPANY
800 Boylston Street
Boston, Massachusetts 02199

March 12, 1999

Mr. Michael McCleish
General Manager
Ocean State Power
1575 Sherman Farm Road
Harrisville, R. I. 02830

Mr. W. C. Taylor
Director Marketing
TransCanada Power Marketing Ltd.
110 Turnpike Road, Suite #203
Westborough, MA 01581

Re: Ocean State Power's Fuel Dispatch Price Calculation

Gentlemen:

Boston Edison Company (BECO), Ocean State Power and Ocean State Power II (together OSP) and TransCanada Power Marketing (TCPM) have recently had several discussions regarding the appropriate methodology for calculating the fuel price to be provided to ISO-New England for determining the dispatch of OSP's generating units.

Since the in-service date of the OSP plant, the fuel dispatch price for the firm gas supply has been the variable cost of gas delivered to the plant per OSP's fuel contracts plus appropriate adders for additives, ash disposal and maintenance.

On 2/12/99, TCPM stated that they determined that the existing methodology in place for determining replacement fuel price for OSP was incorrect, that OSP had provided prices in violation of CRS-11 and that OSP had not been operating in accordance with NEPOOL procedures. TCPM has prepared a procedure under which the price for the firm gas supply is based on an index for gas available at a hub through which the OSP gas is transported. Further, TCPM forced an Operating Committee vote by which it changed the methodology used to determine OSP's dispatch price.

BECO disagrees with TCPM's assertion that OSP provided prices calculated in violation of CRS-11 and NEPOOL procedures. The power buyers represented on the Operating Committee were experienced in NEPOOL issues and processes and did not permit OSP to stray from an acceptable methodology. In addition, NEPOOL audited the methodology used by OSP several times and found the methodology acceptable.

BECO finds that the methodology proposed by TCPM and adopted by OSP is inappropriate because it is based on a self-serving interpretation of certain phrases in CRS-11 and it violates the intent of CRS-11. TCPM has determined that the pricing for the OSP firm gas supply should be based on the Gas Daily Midpoint price for Niagara (NFG, Tenn). BECO believes this index price is not a reasonable basis for determining a "replacement fuel price" for OSP for the firm gas supply. OSP does not purchase its firm gas supply in this market. Instead, OSP purchases its firm gas under more favorable, long-term gas supply contracts. OSP's persistence in using the new methodology to price the firm gas supply for OSP, has resulted in an exorbitant increase in the Fuel Cost Delivered cost, even though OSP's firm gas supply and costs have not changed. Implementation of the new pricing methodology has resulted in a different dispatch of the OSP units than would otherwise occur and has harmed BECO.

The contracts between OSP and BECO, under which BECO purchases a share of the output of the OSP plants, provide for the construction and operation of electric generating facilities and the acquisition of, among other things, firm gas supplies to help assure the long-term viability of the generating plants. Under those agreements OSP is expected to operate as an electricity generation resource and not as a gas/electric arbitrage operation. Actions that TCPM took and that OSP allowed TCPM to take has trampled BECO's rights and caused harm.

This letter provides notice to OSP and TCPM that BECO holds OSP and TCPM financially responsible for increased replacement power costs incurred by BECO which result from the new and inappropriate methodology to calculate fuel prices that TCPM has forced upon OSP.

Sincerely

Rose Ann Pelletier
Manager, Power Contracts

cc: A. J. Pourbaix (TCPL)
P. D. Vaitkus

Attachment
AG-3-1(b)

TransCanada

TransCanada Power Marketing Ltd.
110 Turnpike Road
Suite # 203
Westborough, MA 01581
Telephone: (508) 871-1850
Fax: (508) 898-0433

March 18, 1999

Rose Ann Pelletier
Manager, Power Contracts
Boston Edison
800 Boylston Street
Boston, MA 02199

Re: **Ocean State Power's Fuel Dispatch Price Calculation**

Dear Rose Ann:

You indicate in your March 12, 1999 letter that Boston Edison Company ("BECO") holds TransCanada Power Marketing ("TCPM"), Ocean State Power and Ocean State Power II (collectively, "OSP") "financially responsible for increased replacement power costs incurred by BECO which result from the new and inappropriate methodology to calculate fuel prices that TCPM has forced upon OSP." As you know, TCPM believes that OSP's operations, including the replacement fuel price determination, are consistent with (i) OSP's obligations under the power purchase agreements ("PPAs"), including BECO's PPAs, and (ii) NEPOOL market operations rules which permit sellers, such as OSP, to report their opportunity costs as the unit dispatch price. Accordingly, neither TCPM nor OSP are responsible for any of BECO's allegedly increased replacement power costs. Rather, any consequential costs experienced by BECO, or "harm" as you refer to it in your letter and our various conversations, results solely from BECO's own replacement power arrangements that fall outside of any involvement of TCPM or OSP.

BECO's PPA entitlements have been, and are being, maintained. Section 5.1 of all of OSP's PPAs expressly limit the buyer's entitlement to capacity and energy that "is available from time to time from Unit 1 [and Unit 2]." Nothing in the PPAs preclude OSP from optimizing economic value by not operating the units when market conditions are unfavorable for doing so. Indeed, if it is more economical to sell the gas than it is to generate electricity, then the PPAs require OSP to do so. Section 4.1 of the PPAs vests the Seller with sole responsibility for the operation and maintenance of the plant, with "the objective being to operate and maintain Unit 1 [and Unit 2] as efficiently, economically and reliably as is prudent under prevailing circumstances." OSP's NEPOOL reporting practices are consistent with the PPA's core objective of optimizing economic efficiency under the prevailing circumstances. The dispatch signal reported to NEPOOL simply reflects the market value of alternatives to producing and selling electricity. If greater value can be realized by selling gas, then it is economically efficient to do so and consistent with the PPAs, which expressly contemplate the resale of gas. BECO has shared in this increased value in the form of reduced costs under its PPAs.

BECO's assertions notwithstanding, OSP still operates as an electricity generation resource and has not been transformed into a gas/electric arbitrageur. Over the years a number of gas-fired generators have been dispatched based on the spot price of gas. As discussed below, NEPOOL rules contemplate instances when participating sellers may report their opportunity costs which could result in their plants not being economically dispatched by the ISO. OSP reasonably and appropriately conformed its dispatch reporting methodology to be consistent with current NEPOOL operating practices, as required by Section 4.8 of the PPAs which provides that the units shall be dispatched in accordance with the provisions of the NEPOOL Agreement.

Based on information provided by the Operating Committee, OSP has determined that NEPOOL rules allow sellers to report their "replacement price" or "opportunity cost" of fuel. NEPOOL Criteria, Rules and Standards No. 11 ("CRS-11"), governing "Replacement Fuel Price Determination," provides that all fossil transactions to and from NEPOOL will be "compensated at the price of fuel needed to replace the fuel used in the delivery." The replacement price is measured by the market price of fuel at the company's receiving point. Section 1.3.1 of CRS-11 states that "it should be the price at which fuel burned on a given day would have to be replaced if purchased on that day." Thus, OSP's NEPOOL dispatch is determined by the market price of delivered "replacement fuel" on any given day at the Niagara-Tennessee hub, and not the price under OSP's fuel contract.

To remove any doubt as to OSP's determination of its opportunity costs and compliance with CRS-11, TCPM apprised ISO-New England ("ISO-NE") as to OSP's dispatch pricing methodology and was informed by ISO-NE representatives that OSP's reporting methodology is consistent with NEPOOL procedures. Moreover, in comments concerning NEPOOL market rules filed March 3, 1999 in FERC Docket No. ER99-1374-000, ISO-NE reiterated this view by explaining to the FERC that "the opportunity cost of using the same fuel resource at another time in the same day is a more accurate measure of [a generator's] cost in the NEPOOL market than acquisition cost," and that such approach "is consistent with the traditional NEPOOL measure of marginal cost for fossil fuel units, which uses current market prices for the grade of fuel used rather than a generator's historic cost of acquisition."

You also rely on NEPOOL audits to justify adherence to prior OSP practices. However, it should not be surprising that NEPOOL audits found OSP's methodology to be acceptable because the use of vintage gas contract prices, as you suggest, causes OSP to subsidize the power costs of all other NEPOOL members by charging too little for the power it sells. The purpose of NEPOOL audits is not to reveal opportunities lost by individual sellers but, rather, to uncover situations in which a NEPOOL member overcharges the pool. While CRS-11 may permit sellers to report costs that result in artificially low power prices, more importantly, it also allows the economically efficient practice of using opportunity costs to value fuel.

Finally, TCPM only recently became an active member of NEPOOL -- essentially since we became an entitlement holder to NEPOOL generation. Prior to this time, OSP has relied on the other power buyers, including BECO, to apprise it of the full scope of NEPOOL rules and how they may affect OSP operations. However, now that TCPM understands the

NEPOOL rules first hand, OSP now recognizes that it is not obligated to continue subsidizing the pool by selling energy in hours when market prices, and NEPOOL rules, would dictate alternative action. The bottom line is that TCPM and OSP are fully complying with the PPAs and NEPOOL rules, including CRS-11, as has been recently confirmed by ISO-NE.

Please feel free to call me if you would like to discuss this matter further. As always, we are willing to consider any alternate proposals that BECO may offer.

Sincerely,

Bill Taylor
Vice-President

cc: Mike McCleish
Alex Pourbaix
Paul Vaitkus (BECO)

Attachment
AG-3-1(c)

SULLIVAN WEINSTEIN & MCQUAY
A PROFESSIONAL CORPORATION
COUNSELLORS AT LAW

A. LAUREN CARPENTER
(617) 348-4360
LCarpenter@resq.com

May 17, 1999

BY FAX AND BY MAIL

Michael McCleish
General Manager
Ocean State Power
1575 Sherman Farm Road
Harrisville, RI 02830

Re: **Unit Power Agreement for the Sale of Capacity and Energy from Ocean State Power to Boston Edison Company**

Dear Mr. McCleish:

This firm represents Boston Edison Company ("BECO") in connection with a dispute with Ocean State Power and Ocean State Power II (collectively, "OSP") arising from certain unit power agreements for the sale of capacity and energy from the OSP units. Specifically, BECO disputes OSP's continued resales of natural gas intended for the generation of power at OSP, which have curtailed the power available to BECO from the OSP units, and have increased BECO's costs of supplying power to its consumers. BECO believes that OSP's conduct in this regard constitutes a material breach of the express terms of the unit power agreements, as well as breaches of certain gas arbitrage agreements; constitutes a breach of the implied covenants of good faith and fair dealing in those agreements; and constitutes unfair and deceptive trade practices under Chapter 93A of the Massachusetts General Laws. OSP has also violated the unit power agreements and NEPOOL's rules and its federal statutory authorization by submitting improper and artificially inflated dispatch prices to NEPOOL, in furtherance of its scheme to profit by reselling gas rather than complying with its contractual obligation to produce power.

As a public utility subject to Massachusetts' Industry Restructuring Act, and consistent with its ongoing obligations to consumers, BECO cannot allow OSP to engage in unauthorized actions such as these at the expense of BECO's consumers.

The Unit Power Agreements

In 1985 and 1988, respectively, BECO entered into two separate, but virtually identical, Unit Power Agreements for the purchase of power from two OSP generating units located in Burrillville, Rhode Island (collectively, "the UPA"). Under the UPA, OSP has an obligation to use diligence to produce power up to the determined capacity of the units, and BECO in turn has an obligation to make certain payments to OSP.

A cornerstone of the UPA is OSP's 20-year gas supply contract (with ProGas Limited, for the 1985 and 1988 power agreements, and with Western Gas Marketing Ltd., for the 1988 power agreement; collectively, the "Gas Supply Contract"). The preamble to the UPA provides, among other things, that "Seller has contracted for a firm supply of natural gas to operate [the unit] for a twenty (20) year period," and that "Seller is willing to make available and Buyer is willing to purchase [a specified percentage of] the Capacity and Corresponding Energy of [the unit] for the twenty year period for which the supply of gas has been contracted." *See* UPA at page 1.[1] The Gas Supply Contract is incorporated into and attached to the UPA, *see* UPA Appendix C, and the UPA's effectiveness in the first instance expressly depends on BECO's approval of that contract. *See, e.g.*, UPA §§1.30, 2.2, 2.3(b), (c). The importance of the Gas Supply Contract to the UPA is further underscored by the fact that the UPA makes no provision for OSP to enter into any other gas supply contract without BECO's consent.

The parties' obligations under the UPA are similarly tied to the Gas Supply Contract. BECO's payment obligation under the UPA is based in part on OSP's cost of gas under the Gas Supply Contract. *See* UPA §7.3. The UPA provides that BECO must pay a share of certain of the costs of the OSP units, "whether or not [the Units] generate[ ] and deliver[ ] the Buyer's Entitlement sold herein, or whether or not [they are] capable of generating and delivering such Buyer's Entitlement, without regard to the cause of any failure or inability to generate and deliver Buyer's Entitlement." UPA §7.1.

In exchange for BECO's obligation to continue to pay OSP's costs, however, the UPA affirmatively and unequivocally imposes on OSP the obligation to generate power. Specifically, §5.3 of the UPA provides in pertinent part:

> Seller shall use due diligence to make available to Buyer, regularly and without interruption, Buyer's Entitlement. After the Commercial Date, Seller shall use all reasonable efforts to bring the net output to the level of Design Net Electrical Capability on an expeditious basis and shall continue said efforts throughout the term of this Agreement.

(Emphasis added.) Although §5.3 of the UPA states that "Seller does not guarantee the availability of Buyer's Entitlement at all times" (emphasis added), it provides that OSP

> shall be excused from delivering said Entitlement hereunder and not be considered to be in default if and to the extent that it shall be prevented from so doing for any reason, including but not limited to equipment breakdown, scheduled or unscheduled repairs, maintenance or the failure of Seller's fuel supply. The intent of this provision is that Buyer shall assume the risks of

---

[1] For convenience, references to specific sections of the UPA are to the 1985 agreement

> nondelivery of Buyer's Entitlement caused by the hazards of the business to the same extent as if it were itself operating Unit 1 for the purpose of supplying itself. It is further agreed that Seller shall use all due diligence to resume deliveries of Buyer's Entitlement at the earliest practicable time after cessation of the event causing such nondelivery.

(Emphasis added.) Similarly, §5.4 excuses OSP for nonperformance as a result of events of "force majeure," which are defined as events "beyond the reasonable control of Seller." The plain terms of the UPA thus excuse OSP from its obligation to produce power only by hazards of the business that are outside its control. These terms, as well as the affirmative obligation that the UPA imposes on OSP to continue generating energy, flatly refute OSP's assertion that it has discretion to decide whether or not it will produce any energy.

Finally, the UPA expressly prohibits OSP from reselling gas without BECO's consent, to the extent that the resale curtails BECO's right to power from the OSP units. Specifically, §7.10 provides in pertinent part:

> Seller shall not resell that quantity of gas or related transportation services purchased for [the unit] which is proportionate to Buyer's Entitlement divided by all Purchaser's Entitlements without the consent of Buyer.

This provision is plainly meant to safeguard BECO's entitlement to power and to preclude OSP from selling the gas purchased for the unit rather than producing power.

The Arbitrage Agreements

In late 1996, OSP approached BECO for approval to engage in certain gas/electric arbitrage transactions. OSP proposed selling certain of the gas it received under the Gas Supply Contract, from time to time, rather than using it to produce power. Such an arrangement was plainly inconsistent with the terms of the UPA. Therefore, to establish the terms on which BECO might agree to such transactions, OSP proposed either amending the UPA or entering into a stand-alone agreement. After nearly one year of negotiations relating to the terms of such an arrangement, OSP and BECO ultimately entered into two Arbitrage Agreements in late 1997.

The Arbitrage Agreements, which were virtually identical for each unit, provided terms on which OSP could propose, and BECO could approve or reject, transactions by which OSP would sell on the market a certain amount of the gas supplied to it under the Gas Supply Contract. The Arbitrage Agreements expressly required OSP to give BECO advance notice of each such proposed transaction. The agreements also expressly provided that no such transaction could go forward without BECO's affirmative consent, to be given or withheld on a case-by-case basis, and that BECO's failure to respond to any particular notice of a proposed transaction would constitute a rejection of the transaction.

The parties recognized that BECO's decision to grant or withhold its consent to a particular transaction would depend on whether its potential gain from the sale was likely to exceed the cost of its replacement power during a particular transaction period. The Arbitrage Agreements expressly recognized the possibility that a particular resale transaction could cause damage to BECO, in that BECO would have to purchase power from another source to replace the power that OSP would not be producing when it sold the gas. Accordingly, §5 of the Arbitrage Agreements provides:

> The power Buyers shall be solely responsible for replacing, at their own risk and expense, all energy not delivered by [OSP] by reason of the implementation of a Transaction and neither TCE nor [OSP] shall have any obligation to supply such replacement power nor shall they have any liability in the event a Power Buyer is unable to secure replacement power or is unable to secure such power at a price which would result in an overall credit to the Power Buyer after implementation of a Transaction.

The consent requirement in the Arbitrage Agreements thus ensures that a particular arbitrage transaction will occur only when BECO, on sufficient notice, determines that the market price of gas and its own costs of purchasing replacement power are such that the transaction will be beneficial overall to BECO and its consumers.

The Arbitrage Agreements provided that they would each expire on March 5, 1998, unless earlier extended by the parties, and that "no [gas resale] Transaction shall be entered into for any period which extends beyond March 5, 1998, except with the express written agreement of each Partner, each Power Buyer, and TCE." BECO agreed to a one-year extension of the Arbitrage Agreements, and both agreements expired by their terms on March 5, 1999.

OSP's Unauthorized Resales of Gas

Both before and after the Arbitrage Agreements expired on March 5, 1999, and despite the express prohibitions of such transactions in the UPA and in the Arbitrage Agreements, OSP has engaged in a number of unauthorized transactions by which it has sold on the market gas that it purchased under the Gas Supply Contract. BECO has not granted its consent to any of those transactions; instead, it declined to consent to a proposed December 1998 transaction of which OSP notified it, and it has strenuously objected to the other transactions after discovering them. OSP's sale of gas in February 1999 despite BECO's rejection of the transaction, and its subsequent sales of gas without seeking or obtaining BECO's consent, directly violate the UPA and the Arbitrage Agreements, which expressly require BECO's consent to any such transactions.

For the periods in which it has resold the gas under the Gas Supply Contract, OSP has also failed to produce the full normal output of power at the OSP facilities. OSP's voluntary decision to sell the gas, rather than to use it to make power available to BECO, constitutes a material and unexcused breach of its obligation under the UPA to use due diligence to make BECO's entitlement of power available. Its failure to produce power is not due to any force majeure event or any other event outside of OSP's control, but is a volitional (and economically motivated) act squarely within OSP's control.

Contrary to OSP's assertions, the UPA's requirement that OSP operate the units "efficiently" does not suggest that OSP may use the gas purchased under the Gas Supply Contract to engage in unauthorized arbitrage transactions instead of producing power. Rather, in the context of the UPA, which requires OSP to act diligently to produce power, the UPA's mandate that the units be operated "efficiently" can reasonably be read only as requiring OSP to minimize the costs of producing the power for which BECO is obligated to pay -- and not as allowing it to maximize its own economic benefit from the gas delivered under the Gas Supply Contract.

Accordingly, please be advised that BECO considers OSP's unauthorized resales of gas under the Gas Supply Contract to constitute breaches of the UPA and the Arbitrage Agreements. As BECO has previously notified OSP, OSP's breaches have damaged BECO, in that, to replace the power that OSP has failed to provide, BECO has been required to purchase power under a separate contract with rates higher than those under the UPA.

BECO further believes that OSP's actions have breached the implied covenant of good faith and fair dealing in the UPA, and also constitute unfair and deceptive practices under Chapter 93A of the Massachusetts General Laws. Under Massachusetts law, which governs the UPA, every contract contains an implied covenant of good faith and fair dealing that prohibits either party from taking actions that prevent the other party from obtaining the fruits of the contract. *See, e.g., Anthony's Pier Four, Inc. v HBC Associates*, 411 Mass. 451, 583 N.E.2d 806 (1991); *Pepsi-Cola Metropolitan Bottling Co., Inc. v. Checkers, Inc.*, 754 F.2d 10 (1st Cir. 1985). OSP has engaged in unauthorized gas sales, and has failed to provide BECO with its power entitlement, in contravention of its express obligation to produce power, and despite the express prohibition of unauthorized resales of gas in the UPA and the Arbitrage Agreements. OSP has done so despite the parties' past dealings reflecting their understanding, reflected in the Arbitrage Agreements and otherwise, that gas/electric arbitrage is prohibited under the UPA and the Arbitrage Agreements without BECO's consent, and with full knowledge of the economic harm that such transactions may cause BECO and its consumers. OSP's wholly unjustified and willful breaches of the UPA have prevented BECO from obtaining the power for which it contracted under the UPA, at the expense of BECO's consumers. OSP's bad faith is further demonstrated in its purposeful and unjustifiable manipulation of the NEPOOL reporting rules in an effort to conceal its out-and-out violations of the UPA and the Arbitrage Agreements.

Please be advised that, consistent with its continuing obligations to its consumers, BECO intends to take all steps necessary to recover these increased power costs from OSP, and to enforce OSP's obligation to produce power with the gas under the Gas

Supply Contract. Please be further advised that if OSP continues to engage in such arbitrage transactions without BECO's consent, depriving BECO of the power for which it contracted for its customers, BECO will consider OSP to have committed an anticipatory breach that vitiates BECO's obligations under the UPA.

Accordingly, BECO requests that OSP immediately cease engaging in arbitrage transactions without BECO's consent, and that it acknowledge its liability for the damages incurred by BECO as a result of past unauthorized transactions.

OSP's Violation of NEPOOL Rules by Its Submission of Artificially Inflated Power Costs.

BECO believes that OSP, through its agent TransCanada Power Marketing Ltd. ("TransCanada"), has used the wrong methodology to submit fuel prices to ISO-New England for the purpose of determining the dispatch of OSP's generating units. BECO believes that OSP has done so with the intent of causing ISO-New England not to dispatch OSP's units, an outcome that OSP is attempting to use as a pretext to justify its unauthorized gas sales. Such conduct violates not only OSP's express and implied obligations under the UPA, but also violates NEPOOL's rules and the NEPOOL agreement, both before and after the rules' Second Effective Date.

The controlling NEPOOL rule, CRS 11, §3.3, directs the Lead Participant to report either a conventional fuel price or a proximate fuel price, which price is based upon the variable components of the cost the participant pays for the energy. For many years OSP's fuel prices were appropriately reported to NEPOOL by using the variable cost of fuel delivered to the plant under the Gas Supply Contact as the variable cost of fuel for this purpose. In late 1998, however, BECO refused to consent to OSP's request under the Arbitration Agreements to engage in a gas/electric arbitrage transaction. Thereafter, in mid-February 1999, OSP made a sudden and drastic change from OSP's consistent past practice, and, for the first time, began reporting OSP's fuel cost based upon the market value of gas at Niagara. The new index does not reflect OSP's fuel replacement costs under the Gas Supply Contract, and impermissibly and artificially overstates OSP's actual costs of producing power. This change in OSP's reporting methodology, in response to BECO's refusal to consent to a gas/electric arbitrage transaction, is an unjustified bad-faith tactic intended to manipulate NEPOOL's dispatching of OSP's units to create a pretext for OSP's sales of gas.

Thus, OSP's submission of artificially high bid prices violates not only the NEPOOL rules themselves, but constitutes a further breach of the implied and express terms of the UPA, which provides that power shall be dispatched in accordance with NEPOOL rules, and that OSP shall perform the contract in good faith. UPA §4.8. OSP's unlawful bidding methods also wrongfully deprive consumers of the benefit of economical energy generated with the gas from OSP's favorable Gas Supply Contract. Accordingly, OSP's bids contravene the stated federal purpose of power pooling arrangements such as NEPOOL, which is to "assur[e] an abundant supply of electric energy throughout the United States with the greatest possible economy." *See* 16 U.S.C. §824a (emphasis added). OSP's inflated bids also contravene Massachusetts' Energy Restructuring Act, which similarly seeks to obtain the most economically priced power for consumers. BECO demands that OSP immediately cease its wrongful reporting of OSP energy prices and begin reporting such prices in accordance with the costs of fuel under the Gas Supply Contract.

The reporting of OSP's energy costs to NEPOOL by TransCanada Power Marketing Ltd. also violates the NEPOOL rules after the Second Effective Date, in that, under §14.2 of the Restated NEPOOL Agreement dated July 21, 1998, TransCanada has no right to report OSP's energy costs. Namely, §14.2 of the Restated NEPOOL Agreement provides:

> [f]or a generating unit in which there are multiple Entitlement holders, only one Participant shall be permitted to submit Bid Prices for Energy, Operating Reserve and/or AGC Entitlements for such unit or to direct the scheduling of the unit for any Scheduled Dispatch Period. The Entitlement holders in each unit with multiple Entitlement holders shall designate a single Participant that will be permitted to submit Bid Prices and/or to direct the scheduling of the unit. In the event that more than one Participant is designated, or if the Entitlement holders do not designate a single Participant, then Bid Prices for the unit shall be based on its replacement cost of fuel, which shall be furnished to the System Operator by the Participant responsible for furnishing such information as of December 1, 1996.

OSP is a generating unit in which there are multiple entitlement holders, namely, TransCanada and BECO. BECO has never agreed to designate TransCanada as the single participant, nor has it authorized TransCanada to submit bid prices in accordance with the draft protocol proposed by TransCanada. Accordingly, under §14.2 of the Restated NEPOOL Agreement, OSP's bid prices must be based on the replacement cost of fuel, which shall be furnished to the system operator by the participant who was responsible for furnishing such information as of December 1, 1996. Eastern Utilities Associates was responsible for furnishing such information as of December 1, 1996, but is no longer an entitlement holder in the OSP units. Under §14.2, BECO, the sole remaining entity who was an entitlement holder as of December 1, 1996, should therefore be the participant who has the right to furnish OSP's bid prices to NEPOOL.

Accordingly, please provide BECO with the appropriate upload file that is based on OSP's variable cost per the firm gas supply for Units I and II so that BECO may report such information to NEPOOL for purposes of dispatch in accordance with the methodology used prior to February 1999.

Conclusion

As discussed above, OSP's unauthorized resales of gas under the Gas Supply Contract, as well as its reporting of bid prices based on the market price of gas, rather than the contract price, violate the UPA and the NEPOOL rules, and also constitute breaches of OSP's obligation of good faith and fair dealing under the UPA, as well as violations of Chapter 93A. BECO demands that OSP immediately cease such conduct; that it engage in no further gas/electric arbitrage transactions; that it begin immediately to report OSP's bid prices to NEPOOL using the price under the Gas Supply Contract as its replacement cost of fuel; and that it provide to BECO all pertinent information on OSP's costs so that BECO, as the only remaining entitlement holder as of December 1, 1996, may begin reporting OSP's bid prices to NEPOOL.

BECO considers these breaches and violations by OSP to be extremely serious and detrimental to BECO and its consumers. Please be advised that BECO will take all appropriate steps to enforce OSP's obligations and to obtain redress for the damages that its unlawful acts have caused BECO and its consumers.

Sincerely,

A. Lauren Carpenter

A. Lauren Carpenter

cc: (by fax)
Paul Vaitkus
(by fax and regular mail)
William C. Taylor
Alexander J. Pourbaix

bcc: (by fax)
Cathy Keuthen, Esq.
Rose Ann Pelletier
Joseph Houle

Attachment AG-3-1(d)

SULLIVAN WEINSTEIN & MCQUAY

A PROFESSIONAL CORPORATION
COUNSELLORS AT LAW

A. LAUREN CARPENTER
(617) 348-4360
LCarpenter@resq.com

May 27, 1999

BY FAX AND BY MAIL

Michael McCleish
General Manager
Ocean State Power
1575 Sherman Farm Road
Harrisville, RI 02830

Re: Unit Power Agreement for the Sale of Capacity and Energy from Ocean State Power to Boston Edison Company

Dear Mr. McCleish:

I am writing in response to e-mail messages sent to Joseph Houle at Boston Edison Company ("BECO") from Scott DeGeeter at TransCanada on May 25 and 26, 1999. The first e-mail states in part as follows:

> We take it from your May 17, 1999 letter that you no longer (i.e. no longer since the blanket authorization you gave us last July) authorize the sales of BECO's portion of gas that is excess to the dispatch requirements at OSP -- as such, what do you want us to do with your portion of the gas?

The second e-mail states:

> As per your letter this serves as notice that OSP needs to sell approximately 17,000 MMBtus for gas day Thursday May 26. This gas sale is to manage the gas supply due to ISO dispatch. This is to confirm the voice mail that was left with you. Please contact me to discuss BECO's wishes on this.

Because these messages relate to the dispute that is the subject of my letter to you of May 17, 1999, BECO has asked me to respond to them.

Initially, BECO denies having given OSP any "blanket authorization" with respect to sales of gas. Please identify as soon as possible the basis on which Mr. DeGeeter made this statement.

BECO believes that the requests that it consent to OSP's sales of gas misapprehend BECO's position, as set forth in my letter; are premature, in view of the fact that OSP has not yet responded to that letter; and represent a bad-faith attempt to coerce BECO into consenting to OSP's unlawful conduct, as described in that letter. OSP has an obligation under the Unit Power Agreements to exercise due diligence to use the gas under its fuel supply contracts to produce power for BECO. As set forth in my letter of May 17, it is BECO's position that OSP has breached this duty by deliberately reporting OSP's variable fuel costs to NEPOOL in accordance with the market price at Niagara, rather than the contract price, with the intent that OSP will not be dispatched as often as it would otherwise, so that OSP may sell the "excess" gas rather than use it to produce power.

BECO has in the past not objected to OSP's sales of gas in excess of dispatch requirements when OSP was reporting its variable fuel costs to NEPOOL appropriately, in accordance with the price under its fuel supply contracts or pursuant to interruptible gas pricing when supplemental supplies were required. To the extent that OSP's current "excess" of gas had resulted from such a situation, BECO would likewise not object to the sale of such gas. To the extent that OSP's unlawful and erroneous reporting of its variable fuel costs has caused it currently to have "gas that is excess to the dispatch requirements at OSP," however, BECO reiterates its objection to such conduct. BECO intends to pursue its rights to recover for the harm that OSP has caused it and is continuing to cause it by such misconduct.

Notwithstanding BECO's unequivocal objection to those unlawful acts of OSP which are resulting in the excess of gas, BECO recognizes the need to mitigate its damages. Accordingly, under the duress of OSP's unlawful conduct, as set forth in my letter of May 17, 1999, and without waiving its right to seek damages and other relief for OSP's misconduct, BECO agrees that its portion of gas should be sold, solely for purposes of mitigating BECO's damages.

Sincerely,

A. Lauren Carpenter

A. Lauren Carpenter

cc: (by fax)
Paul Vaitkus
(by fax and regular mail)
William C. Taylor
Alexander J. Pourbaix
Scott DeGeeter

bcc: (by fax)
Cathy Keuthen, Esq.
Rose Ann Pelletier
Joseph Houle

Attachment
AG-3-1(e)

DICKSTEIN SHAPIRO MORIN & OSHINSKY LLP

2101 L Street NW • Washington, DC 20037-1526
Tel (202) 785-9700 • Fax (202) 887-0689
Writer's Direct Dial: (202) 861-9178
E-Mail Address: RumanM@dsmo.com

June 4, 1999

VIA FACSIMILE AND U.S. MAIL

A. Lauren Carpenter, Esquire
Sullivan Weinstein & McQuay
Two Park Plaza
Boston, MA 92110-3902

Re: Unit Power Agreements for the Sale of Capacity and Energy from Ocean State Power to Boston Edison Company

Dear Ms. Carpenter:

Ocean State Power and Ocean State Power II (collectively "Ocean State") have asked us to respond to your letter of May 17, 1999, in which you raise certain issues regarding Ocean State's resales of natural gas purchased in connection with operations under the two identical Unit Power Agreements ("UPAs") between Ocean State and Boston Edison Company ("BECO"). Since we see no useful purpose in litigation by letter, this response will be limited to noting salient points that we believe your letter overlooks or misapprehends. This response does not purport to be an exhaustive elaboration of all of the defenses Ocean State could raise in the event of any possible litigation. Indeed, Ocean State looks forward to an amicable resolution, which we believe can best be achieved through non-adversarial face-to-face discussions.

As discussed below, Ocean State categorically denies that it, or TransCanada Power Marketing Ltd. ("TransCanada"), as Ocean State's Lead Participant for NEPOOL purposes has at any time violated the UPAs or has otherwise acted in bad faith. To the contrary, Ocean State and TransCanada (hereafter collectively "Ocean State") have acted in strict conformity with contractual obligations, NEPOOL rules and standards, good utility practice, and in particular the "objective" articulated in UPA § 4.1, which is "to operate and maintain [the two Ocean State Units] as efficiently, economically and reliably as is prudent under prevailing circumstances."

Ocean State's basic position is largely outlined in the attached March 18, 1999 response by TransCanada's Vice-President Bill Taylor to the March 12, 1999 letter from BECO's Manager of Power Contracts Rose Ann Pelletier.

As the Taylor letter points out, the "Buyer's Entitlement" to which you refer repeatedly is not even on its face an absolute right to continuous power, but rather only a share of such power as is actually generated. Section 5.1 expressly limits the "Buyer's Entitlement" to a right to receive 23.5 percent of "the Capacity and Corresponding Energy as it is available from time to time from [the Units]" and emphasizes that "Buyer's

Entitlement involves no right to receive Capacity and Corresponding Energy when Capacity and Corresponding Energy are not available." Section 5.3 requires no more than "due diligence," which is obviously defined by § 4.1 and the other provisions of the UPAs regarding prudence and efficiency. The UPAs do not require Ocean State to generate electricity when it is inefficient and economically imprudent to do so. Indeed, § 4.1 requires the opposite course of action.

Section 4.8 of the UPAs makes Ocean State's performance contingent upon the units' being dispatched under the NEPOOL Agreement, as amended from time to time and approved by the Federal Energy Regulatory Commission. As the Taylor letter explains, Ocean State determined that the NEPOOL market operation rules in effect prior to May 1, 1999 permitted sellers such as Ocean State to report their opportunity costs (*i.e.*, market prices rather than actual costs under the vintage gas supply contracts) as the unit dispatch price signal.[1] Under the rules in effect since May 1, 1999, there have been no cost constraints upon the bid prices submitted to NEPOOL. It is the selection of bids by the NEPOOL Independent System Operator ("ISO") that determines whether or not the Units are dispatched.[2] If the Units are not dispatched by the ISO, Ocean State then has surplus gas which it resells. The resale of such surplus gas is, therefore, incidental to Ocean State's lawful compliance with the NEPOOL Agreement, as required by UPA § 4.8.

Ocean State has not sold any gas that was needed for the production of electricity, and complied with all of its generation obligations whenever it has been dispatched by NEPOOL. A decision to sell surplus gas occurs only after the Units are instructed not to operate by the ISO after consideration of all lawfully submitted information. Thus, BECO's "right to power" has in no way been "curtailed" as your letter contends at page 3; it is our understanding that the units have been made available at all times for dispatch by the ISO, except for periods of planned and unplanned outages. There is nothing in § 7.10 or elsewhere in the UPAs requiring that all available gas be used for the generation of electricity when it may be imprudent and uneconomic to do so. The intention of § 7.10 is to allow for gas sales from the units when economic and prudent dispatch decisions result in gas being available for sale.

The NEPOOL rules are consistent with the objective of the UPAs in that they cause Ocean State's Units to be dispatched in the most economically efficient manner -- *i.e.*, so as to produce electricity only if doing so creates greater value than selling the gas that would otherwise have been used to produce electricity. All of Ocean State's actions have been designed to maximize the value of the UPAs to power purchasers. BECO has shared in this increased value in the form of reduced costs, which have substantially reduced the Monthly Capacity Charge under § 7.3 of the UPAs.

---

[1] This was determined by analysis of NEPOOL Criteria, Rules and Standards No. 11 and by consultation with the NEPOOL Independent System Operator, ISO New England Inc.

[2] Ocean State's submission of its opportunity costs as its power bid may, but will not necessarily, result in the plant being dispatched off-line. Upon reviewing all of the bids, the ISO may well call upon Ocean State to dispatch, or may reserve otherwise dispatchable Ocean State generation for certain ancillary services or other reliability requirements of NEPOOL.

In any event, BECO has orally consented to Ocean State's sales of gas in the past, and your May 27, 1999 letter agrees to the making of such sales in the future.

None of the foregoing is limited by the agreements that Ocean State and each of the power buyers, including BECO, executed as of January 31, 1997, establishing a "gas/electric arbitrage program" for the benefit of the power buyers. Those agreements have no current significance since they expired by their terms on March 5, 1999. Moreover, they did not purport to establish exclusive rules for the disposition of surplus gas under all circumstances, and could not have trumped Ocean State's right and obligation to conform its dispatch to NEPOOL rules and to act in a prudent and efficient manner.

Finally, BECO's view that it, rather than TransCanada, should be the Lead Participant is belied by, inter alia, the vote of the Operating Committee at its meeting on December 1, 1998. The minutes of that meeting record the selection of TransCanada by the vote of a majority of the Committee members pursuant to § 4.2 of the UPAs.

As noted in your letter at Page 5, the root cause of the dispute arises from the fact that BECO's power costs are higher under its alternative power purchase contracts than under the Ocean State UPAs (and prevailing market prices). BECO's alternative arrangements cannot create rights under the PPA that do not exist, nor should BECO's arrangements cause Ocean State to penalize its other power buyer.

As BECO has previously been advised, Ocean State is willing to modify the UPAs so as to mitigate harm to BECO as a result of its alternative power purchase arrangements. For example, Ocean State believes there may be an opportunity for a power swap arrangement in combination with revisions to the UPA that would enable BECO to obtain cost-effective power, without harming Ocean State and its other power buyer. However, because Ocean State does not know the details of BECO's other power contracts, we believe it would be more appropriate for BECO to suggest how such a transaction might best be structured. In this light, we suggest the scheduling of a face-to-face meeting to explore the opportunities for resolution of the issues concerning BECO's relationship with Ocean State.

Sincerely,

Kenneth M. Simon
Michael J. Rustum

cc: Mr. Michael L. McCleish
Mr. William C. Taylor
Mr. Paul Vaikus
Mr. Doug Horan

OFFICE MEMORANDUM

Boston Edison Company

To: Jeri Purdy

From: Joe Houle
Mail: P222 Phone: 3496

Date: 25-Jul-91

Subject: Ocean State Power – Cost of EAF BONUS or PENALTY

Distribution:
Ron Barber, Roy Daniel

The power purchase agreement stipulates that an adjustment to the monthly capacity charge for unit equivalent avalibility will be computed beginning in the 7th month of commercial operation. Appendix F stipulates that this method of calculating the adjustment shall remain in effect for 120 months unless extended by agreement. It provides that OSP will calculate a monthly Equivalent Availability Factor (EAF), expressed as a percentage, in accordance with NERC/GADS standards, except that such EAF will not be increased or decreased by Equivalent Seasonal Derated Hours.

A Rolling Average Equivalent Availability Factor (RAEAF) will be computed equivalent to the arithmetic average of the monthly EAFs for the preceding twelve full calendar months. It being understood that only the months beginning after the sixth full month of operation are included.

If the RAEAF exceeds the target of 80%, an additional charge is computed as follows:

$$\frac{\text{RAEAF} - 80}{100\%} \times \text{Number of hours in the month} \times \$5{,}460 \times \frac{\text{Current Net Investment Base as of the first day of the month.}}{\$163{,}500{,}000}$$

Substituting June 1991 Net Investment Base, the July hours and 81% RAEAF, that number equals:

$$\frac{81 - 80}{100\%} \times 744 \times \$5{,}460 \times \frac{\$235{,}314{,}121}{\$163{,}500{,}000}$$

$$1\% \times \$4{,}062{,}240 \times 143.923\%$$

$$\$58{,}465$$

BECO's monthly charge would be $27,476 per percentage point above 80% that OSP maintains the EAF. This is calculated based on our share of the unit being 47%. This would be a BONUS payment to OSP.

($58,460 X 47% = $27,476)

If the RAEAF does not achieve the target of 80%, the monthly capacity charge shall be decreased as follows:

$$\frac{80 - \text{RAEAF}}{100\%} \times \begin{array}{c}\text{Number of hours}\\ \text{in the month.}\end{array} \times \$3{,}760 \times \frac{\text{Current Net Investment Base as of the first day of the month.}}{\$163{,}500{,}000}$$

Because $3,760 is 69% of the $5,460 number used in the BONUS calculation, we can quickly estimate that the PENALTY will be approximately 69% of the BONUS amount or $18,958 per percent that the RAEAF is below the 80%.

If OSP achieves the target of 80% RAEAF there is no BONUS or PENALTY.

Attachment
AG-3-1(g)

OFFICE MEMORANDUM

Boston Edison Company

To: Files

From: Joe Houle
Mail: P222 Phone: 3496

Date: 25-Jul-91

Subject: Ocean State Power – Equivalent Availability Factor (EAF) Controversy

Distribution:
Ron Barber, Cathy Keuthen

The Operating Committee Meeting yesterday provided some clarification of OSP's interpretation of the contractual language indicating how the EAF calculation should be performed. Their handout, made available at the June meeting, is attached for reference.

The power purchase agreement provides for the calculation of an EAF adjustment to increase or decrease the monthly capacity charge based on Equivalent Availability Factor. The calculation that OSP proposes to do allows for recognizing deratings only when the unit cannot achieve according to the performance curve when the ambient air temperature is warmer than 59 degrees Farenheit. At 59 degrees or colder the unit would be run at base load if requested, generating at up to 268 MW and would not recognizine any derating below the performance curve for the EAF calculation unless it fell below 250 MW.

In a nutshell, OSP's argument is:

1) We contracted to purchase a share of the output of a unit rated at 250 MW at ISO;
2) The gas supply and gas transportation contracts that we have reviewed and approved provide for 50,000 MCF per day of natural gas to fuel the unit;
3) The 50,000 MCF per day is only enough fuel to generate 250 MW of power over a 24 hour period at 59 degrees Farenheit;
4) OSP should not be penalized for not achieving above the 250 MW because that is all that is assured by the fuel supply.

At present the unit is rated along the performance curve for NEPOOL purposes. This means that the plant is expected to produce power at the rate of 268 MW at 20 degrees Farenheit and 238 MW at 90 degrees and up to ratings along a curve between those two temperatures. BECO will be penalized by NEPOOL if the unit fails to live up to those ratings by a capability responsibility adjustment and PIP charges. In addition there could be some problems regarding GUPP ratings on the unit.

According to my understanding, the EAF adjustment is part of the power purchase agreement so that OSP could be rewarded for providing a generation source with acceptable availability to generate up to its rated capability when called upon or penalized for its failure to live up to its claimed rating. Interpreting the EAF by drawing upon factors from other agreements relating to the OSP units is stretching the point. There could be other conditions, factors or situations that are not presently recognized as having an impact on the unit that could completely eliminate our ability to assess an EAF deficiency charge if OSP's interpretation is accepted.

Subject: Ocean State Power – Equivalent Availability Factor (EAF) Controversy

There is no dispute that a fuel shortage question could have an impact on what the plant produces. As of this time, Tenneco has not required OSP to stop taking gas when its daily quantity had been consumed. If OSP believes that problem will occur, action could be taken to evaluate the cost of losing some of the unit's rating as compared to the cost of securing additional fuel supplies and taking appropriate action.

A committee of the power purchasers will meet to discuss the OSP interpretation of the applicable section of the agreement and the potential costs and benefits of changing some of the forms filed with NEPOOL describing the ratings and capabilities of the units. Some action must be taken soon by the Operating Committee to accept or refute OSP's interpretation because the EAF adjustment begins as a component of the monthly charge with the July bill.

Attachment
AG-3-1(h)

OFFICE MEMORANDUM

Boston Edison Company

To: Cathy Keuthen

From: Joe Houle

Mail: P222 Phone: 3496

Date: 29–Jul–91

Subject: Ocean State Power – Equivalent Availability Factor (EAF) Controversy

Distribution:
Ron Barber

I need correct a comment made in my memo, dated July 25, 1991, with the same subject.

The last sentence on that memo is incorrect in that it is Ron Barber and Jeri Purdy's position that BECO will not let this OSP interpretation of the EAF stand unchallenged. We view the OSP interpretation as an attempt to amend the purchase power agreement and have told them so at the last Operating Committee meeting.

The first sentence in the last paragraph indicates that a committee of power purchasers will be meeting to discuss the OSP interpretation. Apparently, the other power purchasers had not scrutinized the possible ramifications of the OSP interpretation. The action that may be taken by the committee could be to provide guidance to OSP regarding the information provided to NEPOOL via the forms completed to identify the charasteristics, capability and operating parameters of the unit. The committee may also voice disapproval sufficiently so that OSP could reconsider their interpretation of that contract language.

OCEAN STATE POWER
P.O. Box 561, HARRISVILLE, RHODE ISLAND 02830 TELEPHONE (401) 568-9550 • TELEFAX (401) 568-1999

MEMORANDUM

OP-060-Y
0308

To: Ocean State Power Operating Committee

From: Bob Warburton, General Manager

Date: January 24, 1992

Subject: Equivalent Availability Factor Calculation

I have received Fernando DaSilva 's letter of January 6, 1992 outlining the position of the Power Buyers regarding the methodology OSP has presented for calculation of the Equivalent Availability Factor (EAF). As stated in that letter, the only point of disagreement is with respect to a situation in which fuel, above contract amounts, is unavailable and there is some equipment problem which limits the unit.

In order to resolve this issue, OSP will use the methodology outlined in Mr. DaSilva 's letter, including the situation referred to above.

The following summarizes the methodology that will be used by OSP:

1) Unit capability will be measured based on the Temperature-Load Curve supplied to REMVEC and will include duct burner capacity. Capability will be calculated hourly and be based on the ambient temperature at the plant across the hour.

2) If plant equipment is 100% available and OSP is unable to obtain fuel in excess of contract amounts, then EAF will not be reduced, even though unit output will be restricted. Power Buyers will be notified promptly of any fuel restrictions.

3) Whenever equipment problems limit unit capability, EAF will be reduced by the amount of the limitation. This reduction will be calculated hourly based on the maximum capability at the ambient temperature for that hour and will be in terms of Equivalent Unit Derated Hours. If the unit is restricted by equipment problems and further restricted by fuel constraint, the EAF will be reduced only by the amount caused by the equipment problems.

We have been using our proposed methodology since July 1991 and to the best of our knowledge have not had an occurrence of a fuel restriction and equipment restriction simultaneously. Therefore, all previous EAF calculations are in accordance with this procedure. We propose that there is no effect in applying this methodology to past billings and therefore no adjustment should be required.

Please notify me of your concurrence with this position, or of any areas of disagreement.

Thank you for your time and patience.

cc: J.Chris Terajewicz
A.Sloboda

Attachment
AG-3-1(j)

BOSTON EDISON
800 Boylston Street
Boston, Massachusetts 02199

February 13, 1992

Mr. Robert Warburton, General Manager
Ocean State Power
P. O. Box 561
Harrisville, RI 02830

RE: Availability Charges

Dear Bob:

Boston Edison Company (BECo) provided notice of a dispute regarding the Availability Charge included in the monthly billing from Ocean State Power (OSP) for the periods of July 1991 through November 1991. As a result of discussions among the power purchasers, we proposed a methodology that would be appropriate in computing the Availability Charge. Your acceptance of that proposal as indicated in your letter of January 24, 1992 permits BECo to inform you that we withdraw our notice of dispute related to the Availability Charge for those bills.

I understand that you stated that no adjustments to billings are needed because OSP's calculation of the Availability Charge has not resulted in charges computed in violation of the accepted methodology.

Sincerely,

RB Barber

Ronald B. Barber, Manager
Wholesale Contract Management Division

cc: J. Purdy
C. J. Keuthen
J. Houle
OSP Operating Committee

Information Request AG-3-2

Please itemize and quantify the dollar amounts of all outstanding claims and disputes brought by the Company against Ocean State Power associated with the Ocean State Power contracts. Please also provide for each claim and dispute the annual accumulation of each since the contract's inception along with an estimate of the amount of each for each year for the remaining term of the contract.

Response

There are no outstanding claims or disputes. See the Company's response to Information Request AG-3-1.

Information Request AG-3-3

Referring to Exhibits NSTAR-RBH-5, and NSTAR-RBH-6, please recalculate the amounts shown on those exhibits, changing only the after-tax discount rate to the pre-tax discount rate.

Response

CONFIDENTIAL ATTACHMENTS

The analyses set forth in Exhibit NSTAR-RBH-5, and Exhibit NSTAR-RBH-6 were used as a "screening tool" to compare and evaluate proposals (Tr. at 89-90, 101 [D.T.E. 04-60]) and do not directly affect Mr. Lubbock's calculation of customer savings (Tr. at 101, 200-202 [D.T.E. 04-60]). However, even as a screening tool, it would be inappropriate to increase arbitrarily the discount rate, as requested in the question. This level of discount rate would imply an unreasonably high return on common equity of 22.1 percent. Nonetheless, in order to be responsive, Attachment AG-3-3(a) **(CONFIDENTIAL)** and Attachment AG-3-3(b) **(CONFIDENTIAL)** provide the requested exhibits. It should be noted that even using this inappropriate analysis, the OSP transaction would show almost a 5 percent savings over the existing agreements.

The question implies that it would be appropriate to perform cash-flow analysis in a manner that ignores taxes. This is incorrect and misleading. As shown in Attachment AG-3-3(c), it is clear that discounting cash flows at a rate other than after tax cost of capital produces results that are not useful in investment analysis. The Company has attempted to provide a simple example to explain that using a discount rate other than the "after-tax discount rate" of the cost of capital also called the weighted average cost of capital ("WACC"), produces distorted and misleading results.

The principle of discounted cash flow is to compare the after-tax cash flow (cash in) to the after-tax cost of that cash flow (cash out). If the investor gets back more cash than he pays out after including the cost of the money, the investor gains and has a profitable investment. In most long term investments,[1] the after tax cash flow (ignoring interest cost which is included in the weighted average cost of capital) is discounted at the after-tax WACC and by discounting the investment at this rate the investor can conclude how

---

1 Something other than the Company's target capital structure and marginal cost of debt and equity may be used on a specific project where the size is significant, the risk is different from the normal course of business or the funding may be specific.

much more he or she is worth on the day the investment is made and the value of the investment is termed the Net Present Value ("NPV").

Attachment AG-3-3(c), page 1 shows an example of an investment of $1 million in 2004 (line 2), which is recovered ten years later in 2014. The investment is assumed to be fully tax deductible in 2004 and the return of the investment in 2014 is assumed to be fully taxable in 2014, as shown on line 3, to give the investment cash impact (cash out) on line 4. Line 5 shows the "allowed return" on the investment to recover the financing cost. This return of $78 thousand a year is calculated using the required return on rate base ("RRRB")[2] of 13 percent as calculated on lines 9 through 13 (column 2013) multiplied by the net cost of $600 thousand on line 4 (column 2004). The allowed return is taxable at the 40 percent assumed tax rate on line 7 to arrive at the net income on line 7. The total cash flow is shown line 8. If this cash flow is discounted at the WACC on line 13 (column 2006) the Net Present Value is zero. This is the correct answer. The simple proof that the WACC is the correct discount rate to use can be seen by seeing that the NPV on line 14 (column 2006) is zero, meaning that the revenues from the project exactly equal the funding cost of the project. In other words the investment just returns the cost of the investment and thus the company is indifferent as to whether to make the investment or not. Any additional revenue makes the project attractive with a positive NPV. Any lower revenue makes the project unattractive with a negative NPV.

However, if one discounts this cash flow at the RRRB as shown on line 14 (column 2013) the value appears to be negative $167 thousand meaning that the project should not be undertaken. This analysis and this conclusion are wrong because the RRRB is not an appropriate discount rate. Alternatively, one could discount the pre-tax flows on line 15 by the RRRB and arrive at a discounted value of negative $275 thousand, which is even more misleading. In this question the WACC appears to have been confused with the RRRB, which might be termed the pre-tax discount rate. The RRRB is the interest and equity return plus an allowance for tax on the return on equity. One could call this RRRB, the "required return for cost of service purposes" or "pre-tax required return". It is not a "discount rate" and should not be confused with a "discount rate". Finance theory cautions users NOT to use a pre-tax discount rate: "[y]ou should always estimate cash flow on an after-tax basis. Some firms do not deduct tax payments. They try to offset this mistake by discounting the cash flows before taxes at a rate higher than

---

2 Regulators allow a utility to recover sufficient money to repay investors their required return and no more. The RRRB is designed to give a zero NPV for the project.

the opportunity cost of capital. Unfortunately, there is no reliable formula for making such adjustments to the discount rate."[3]

Attachment AG-3-3(c), page 2 shows the 22.1 percent cost of equity that gives a WACC of 12.87 percent or the "pre-tax" RRRB. While the Company would be willing to accept this as an allowed return on rate base, it considers that the Department might find the level higher than their currently allowed returns.

---

[3] Principles of Corporate Finance, Brealy, Myers, Sick, Giammarino 1990 ISBN: 0-07-549923-1 page 100

Calculation to prove that the discount rate on investment cash flows must be after tax

Amounts in $1,000

1 Required return on rate base (RRRB | 12.9% | (input for scenario purposes

Present Value Cash Flow Analysis

#		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	References
2	Investment and return of investment	(1,000)										1,000	$1M investment in 2004 recovered in 2014
3	Tax at 39.225%	392	0	0	0	0	0	0	0	0	0	(392)	Line 2 times 39.225%
4	Cash out	(608)	0	0	0	0	0	0	0	0	0	608	Line 2 plus line 3
5	Allowed Return		78	78	78	78	78	78	78	78	78	78	After tax investment, line 4 in 2004, times RRRB in line 1 above
6	Tax at 39.225%	0	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	Line 5 times 39.225%
7	Cash In	0	48	48	48	48	48	48	48	48	48	48	Line 5 plus line 6
8	Net Cash flow	(608)	48	48	48	48	48	48	48	48	48	655	Line 4 plus line 7
	Cost of capital	Share	Cost	Weighted Average									
9	Equity	50.0%	12.0%	6.00%							6.00%		assumed 50% Equity at 12% Cost of Equity
10	Debt	50.0%	6.0%	3.00%							3.00%		assumed 50% Debt at 6% Cost of Debt
11	Tax Shield on Debt			-1.18%									Line 10 times 39.225%
12	Tax Equity Gross up										3.87%		Line 13 times 39.225% / 60.775% (*)
13	Cost of Capital = Hurdle Rate			7.82%		Required Return on Rate Base (RRRB					12.87%		Sum lines 9 thru 11
				12.87%									
14	Project Net Present Value at Company cost of Capita		7.8%	$ -		Project Value discounted at RRRE					$ (167)		Present Value of Cash flow on line 7
15	Pre-tax flows	(1,000)	78	78	78	78	78	78	78	78	78	1,078	Line 2 plus line 5
16						Project Value discounted at RRRE					$ (275)		Discount of line 15 at the RRRE

* Tax Equity Gross-Up: The equity return is an after tax amount and thus represents 60.775% of the pre-tax amount. Dividing by 60.775% converts the after-tax amount to a pre-tax amount. If one multiplies this pre-tax amount by 39.225% one arrives at the amount of tax that must be paid.

Calculation of the required equity cost to give a 12.87% WACC

Amounts in $1,000

1	Required return on rate base (RRRB)	21.2%	(input for scenario purposes)

Present Value Cash Flow Analysis

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	References
2	Investment and return of investment	(1,000)										1,000	$1M investment in 2004 recovered in 2014
3	Tax at 39.225%	392	0	0	0	0	0	0	0	0	0	(392)	Line 2 times 39.225%
4	Cash out	(608)	0	0	0	0	0	0	0	0	0	608	Line 2 plus line 3
5	Allowed Return		129	129	129	129	129	129	129	129	129	129	After tax investment, line 4 in 2004, times RRRB in line 1 above
6	Tax at 39.225%	0	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	Line 5 times 39.225%
7	Cash In	0	78	78	78	78	78	78	78	78	78	78	Line 5 plus line 6
8	Net Cash flow	(608)	78	78	78	78	78	78	78	78	78	686	Line 4 plus line 7

		Share	Cost	Weighted Average			References
	Cost of capital						
9	Equity	50.0%	22.1%	11.05%		11.05%	assumed 50% Equity at 12% Cost of Equity
10	Debt	50.0%	6.0%	3.00%		3.00%	assumed 50% Debt at 6% Cost of Debt
11	Tax Shield on Debt			-1.18%			Line 10 times 39.225%
12	Tax Equity Gross up					7.13%	Line 13 times 39.225% / 60.775% (*)
13	Cost of Capital = Hurdle Rate			12.87%	Required Return on Rate Base (RRRB)	21.18%	Sum lines 9 thru 11
14	Project Net Present Value at Company cost of Capital		12.9%	$ -	Project Value discounted at RRRB	$ (203)	Present Value of Cash flow on line 7

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	References
15	Pre-tax flows	(1,000)	129	129	129	129	129	129	129	129	129	1,129	Line 2 plus line 5
16						Project Value discounted at RRRB					$ (335)		Discount of line 15 at the RRRB

* Tax Equity Gross-Up: The equity return is an after tax amount and thus represents 60.775% of the pre-tax amount. Dividing by 60.775% converts the after-tax amount to a pre-tax amount. If one multiplies this pre-tax amount by 39.225% one arrives at the amount of tax that must be paid.

Information Request AG-3-4

Referring to Exhibits NSTAR-RBH-5, and NSTAR-RBH-6, please recalculate the amounts shown on those exhibits, changing only the after-tax discount rate to the pre-tax discount rate and using the power and fuel costs and prices so that they are fixed at the most recent numbers for the entire period.

Response

The analyses set forth in Exhibit NSTAR-RBH-5, and Exhibit NSTAR-RBH-6 were used as a "screening tool" to compare and evaluate proposals (Tr. at 89-90, 101 [D.T.E. 04-60]) and do not directly affect Mr. Lubbock's calculation of customer savings (Tr. at 101, 200-202 [D.T.E. 04-60]). However, even as a screening tool, it would be inappropriate to increase arbitrarily the discount rate, as requested in the question. This level of discount rate would imply an unreasonably high return on common equity of 22.1 percent. See also response to Information Request AG-3-3. Nonetheless, in order to be responsive, Attachment AG-3-3(a) **(CONFIDENTIAL)** and Attachment AG-3-3(b) **(CONFIDENTIAL)** provide the requested exhibits. It should be noted that even using this inappropriate analysis, the OSP transaction would show over 20 percent savings over the existing agreements.